Smart Transmission Grids Vision for Europe: Towards a Realistic Research Agenda

Luigi Vanfretti, Dirk Van Hertem and Jan Ove Gjerde

Abstract Smart grids have attracted significant attention lately, and one can even speak of hype. However, much of the attention is paid to the distribution side and consumer interaction. Nevertheless, also at the transmission-level important improvements can be achieved through farsighted and careful intelligent grid design and implementation. This chapter describes and proposes a realistic research agenda in which smart transmission grid (STG) research may operate, with focus on operational planning and operations of the pan-European electricity grid. Firstly, a research outlook seen from current European policy is laid out to redefine the most consequential research directions liked to the needs of transmission systems from real time up to planning. Secondly, operations (real time to hours) of the transmission system are discussed, and monitoring and control technologies that can be achieved through the application of synchronized phasor measurement technology are highlighted as a means toward a STG. Next, challenges related to planning (hours to years) are discussed keeping in mind the need of flexibility, coordination, and new methods for assessing system security. Going beyond the purely academic point of view, this chapter specifically aims to bring a realistic approach toward research for electric power transmission to be able to transform into a STG.

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1 Introduction

Smart grids have attracted significant attention lately, even so that one can speak of a hype. Smart grids can be seen as energy systems that enable optimal operation of the energy system through improved measurements and better control, and this while taking into account all stakeholders involved. The raising interest in "smart grids" has prompted an ever-increasing wave of discussion regarding a more disruptive introduction of information and communication technologies (ICT) to increase efficiency in electricity delivery and power network management. However, much of the attention is paid to the distribution side and the consumer interaction [6, 26]. In particular in Europe, the STG has remained in the background, often using the argument that "the transmission system is already smart."

Synchronized phasor measurement units (PMU) are a notable exception to this. Together with their supporting ICT infrastructures, PMU data applications form an important of many smart grid implementation plans. Nevertheless, the penetration of this technology in the European power system is lagging the development in the USA [5]. However, at the transmission level, there are also other important improvements that can be achieved through farsighted and intelligent grid design and implementation. These improvements are indispensable to operate future electric power systems. This future system will be challenged by unpredicted uncertainties brought upon by a higher penetration of renewable and variable energy sources, limited investments in transmission assets, and an ever higher demand for a more secure supply of electric energy at the lowest possible cost.

Many of these improvements are not ready to be immediately implemented in the current system. There is a specific need for research on some key aspects of the smart transmission system which are deemed essential for the full development and utilization of the future grid. The demonstration of research in real applications is essential in order to get the results validated and the innovations be used in the field. However, a significant portion of the ongoing research seems to be out of touch with reality. This problem arises from the fact that many theoretical approaches are not benchmarked in a lifelike simulation environment using realistic test systems, approaches that do not sufficiently take into account current installations, communication protocols, practices, and operation. Also the non-technical and organizational (or regulatory) background is not sufficiently taken into account. In a nutshell, "artificial" research environments, while useful for discussing theoretical concepts, limit practical implementations and may be unfit to cater to measurements, data, and organizational aspects arising in the real power network. It becomes climacteric to realize that several limitations and boundaries conditions exist and must be taken into account in order to avoid oversimplified or overly optimistic solutions that are not applicable in reality.

In this chapter, the desired framework in which STG research must operate is described, and some policy incentives are outlined. For this, the focus is on the transmission system itself, and more specifically its operational planning and operations. Section 2 lays out the research outlook as seen from current European policy, hence helping redefine the most consequential research directions. A STG framework from real-time operations up to planning is developed. Section 3 focusses on the operations (real time to hours) of the transmission system. We discuss several considerations that need to be considered so that monitoring and control of smart transmission grids (STGs) can be practically achieved through synchrophasor measurement technology (SMT). In Sect. 4, we discuss a number of challenges that are related to system planning (hours to years). The changes that are needed because of the rapid increase of generation from variable and less controllable energy sources are discussed. Increased flexibility, coordination, and a new way of looking at system security are discussed.

Within this chapter, it is not the authors' intention to give a comprehensive overview of all the outstanding issues and their binding research, but rather to cherry-pick some key challenges and potential pitfalls within smart transmission system research and development.

2 Smart Transmission Research Defined

2.1 A European Perspective on Research Needs

A definition of smart grids is given by the SmartGrids European Technology Platform [48]:

> A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies.

The same organization identifies key research areas in its strategic research agenda for 2035 [49], where the main transmission challenges are listed as follows:

New technologies: that improve flexibility and storage and allow long-distance energy transmission. The development of these new technologies will include upgrades in terms of materials, component reliability, and automatic controls.
Improved ICT technologies: to enhance monitoring, control, and modeling of the grid.
Smooth transition path: through investments at the current stage that are not compatible with developments of the future system.
Legal framework and market structures: to enable the different stakeholders to optimize the use of the energy system in the most optimal, "smart" manner including correct allocation of costs and benefits among stakeholders.
Socioeconomic incentives: to allow the necessary infrastructure investments those are required to be performed.

The European Commission communicated in its "Blueprint for an integrated European energy network" [16] that it is necessary to have "rapid investments" in order to ensure "(1) a competitive retail market, (2) a well-functioning energy

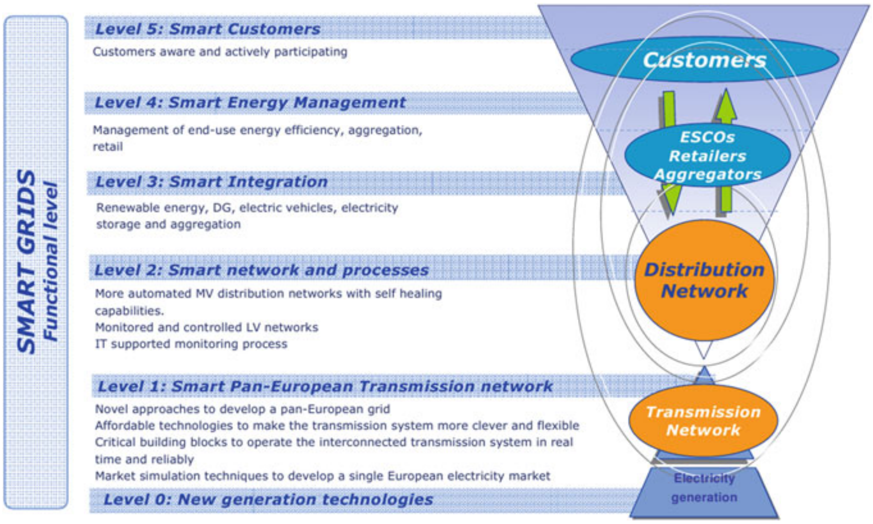

Fig. 1 Functional levels of the smart grid according to European Electricity Grid Initiative [17]

services market which gives real choices for energy savings and efficiency, (3) the integration of renewable and distributed generation, and (4) to accommodate new types of demand, such as from electric vehicles." Next to these technical incentives, there is also a need for an update of the legal framework and to adapt legislations taking into account smart grids and smart meters [3, 51]. A higher transparency within the smart grids and an information platform is needed [16]. Much of this vision is also shared by the European Regulators Group of Electricity and Gas (ERGEG) position paper on smart grids [8, 47]. The regulating authorities are the responsible to provide the correct framework in which the different stakeholders can develop and use the smart grid. Performance indicators are seen as an important aspect in order to the development of a correct framework. Furthermore, a further harmonization of regulation and a regulatory framework which is consistent on a longer-time basis is an absolute requirement for the successful development of efficient smart (transmission) grids.

The European Electric Grids Initiative (EEGI) has indicated in its roadmap for RD&D 2010–2018 [17] a number challenges for the upcoming years. The document identifies 3 main action areas for the development of the future grid: (1) the integration of new generation and consumption models, (2) a coordinated planning and operation of the pan-European grid, (3) new market models to maximize European welfare. The smart grids field is subdivided in different functional levels (see Fig. 1). Within the STG level, the EEGI indicates four main research domains: the pan-European grid architecture, power technologies, network management and control, and market rules. For each of these four areas, specific

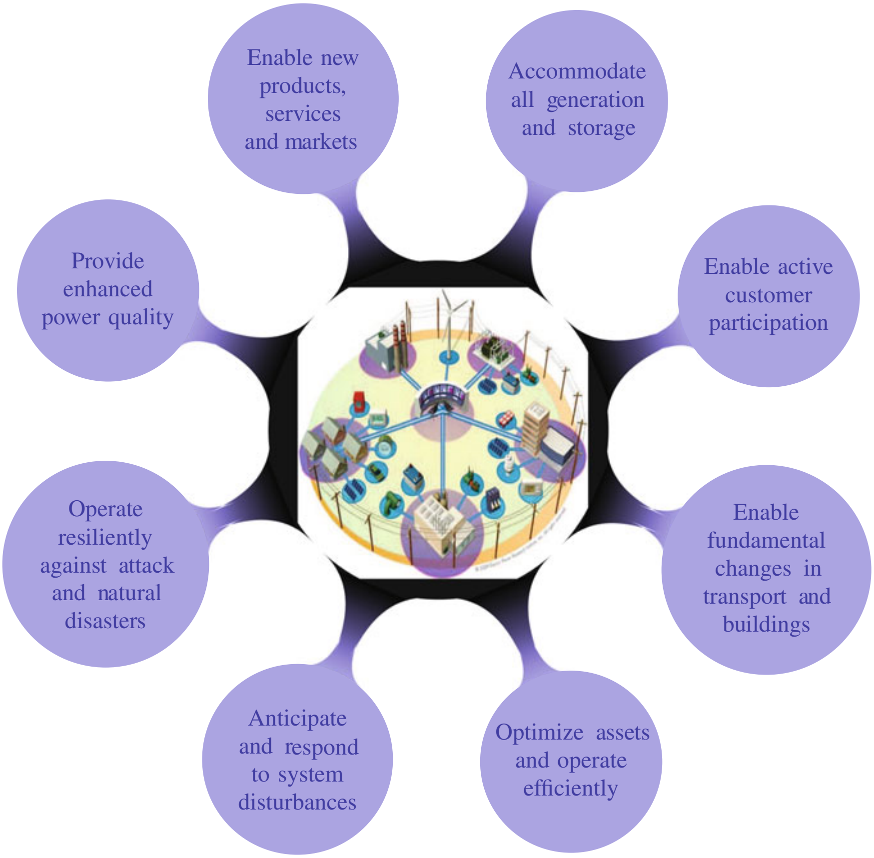

Fig. 2 The different characteristics associated with smart grids. Smart grids can address a number of issues, usually multiple ones at the same time. Based on Department of Energy (DOE) [10]

RD&D activities are proposed. Observe in Fig. 1 the smart transmission network for the increased coordination between system operators (both TSO and DSO).

Numerous other definitions exist, which can be technology oriented, more functional or based on the benefits of the smart grid. It is important to note that in general, smart grids also have a specific regional connotation. While in Europe smart grids are often praised for their ability to provide a transition to a more sustainable energy system with more renewable energy sources and lower energy prices, the emphasis in the USA is more placed on reliability and system automation, and in countries such as India and China, the smart grid is seen as an enabler to manage the rapid growth of new generation, often located far from the load centers (Fig. 2).

2.2 A Transmission System Perspective and Research Framework

From the discussion above, it is relevant to ask what is the impact in maintaining the "status quo" in the activities that a transmission system operator? That is, maintaining the assumption that "the transmission system is already smart." The recently completed ENTSO-E Research & Development Roadmap 2013–2022 [19] and Implementation Plan [18] make it clear that there needs to be a long-term perspective to face the challenges that the European system will meet while adopting the vision of the R&D plan relating to security of supply, adequacy, and energy sustainability. These challenges are coupled with the European climate energy objectives defined in the European Union's "20-20-20" targets and the European Commission's Roadmap 2050. This section provides a framework for identifying key areas that can help in focusing research activities to support the vision of the ENTSO-E R&D Roadmap and Implementation Plan.

As illustrated in Fig. 3, the current grid operation and planning approach and related technologies may not be suited to meet long-term goals, although, they might suffice today's needs. Starting from a timescale perspective, today's technical solutions have to aid in maintaining grid stability from the millisecond to the seconds basis, allow for adequate balancing in the minutes to hours time frame, and guarantee reliability in both operational as well as long-term planning. However, technical and non-technical constraints brought about by uncertainties in production and demand, physical and cyber-vulnerabilities, as well as market forces, regulation, and legislation and can pose unforeseen difficulties to both the philosophy and technical solutions available for a transmission system operator to guarantee security of supply and reliability facilitating a well-functioning electricity market.

Current solutions in the form of methodologies, software tools, and different technologies cannot take into consideration all of the new constraints posed above without substantial harmonization. A negative impact therefore will translate in reduced grid stability, security of supply, inadequacy in power supply and insufficient grid developments to meet with new constraints. Such negative impacts are mapped together with their corresponding timescales in Fig. 4, as it can be observed, these negative impacts are product of today's solutions not being able to meet different constraints.

For a transmission system to be able to meet the constraints listed above, as illustrated in Fig. 3, smart grid solutions need to be developed. This would imply the transition into smart operation and smart operation philosophies and technologies which can enable the adoption of new methodologies for analysis, modular and extensible software for design and optimization, and high-voltage and high-power technologies that can help meeting these new constraints. Such solutions and technologies are identified in Fig. 5 for each timescale, together with a mapping of different technical and non-technical constraints under which they will operate. Starting from the fastest timescale, we identify what are the different

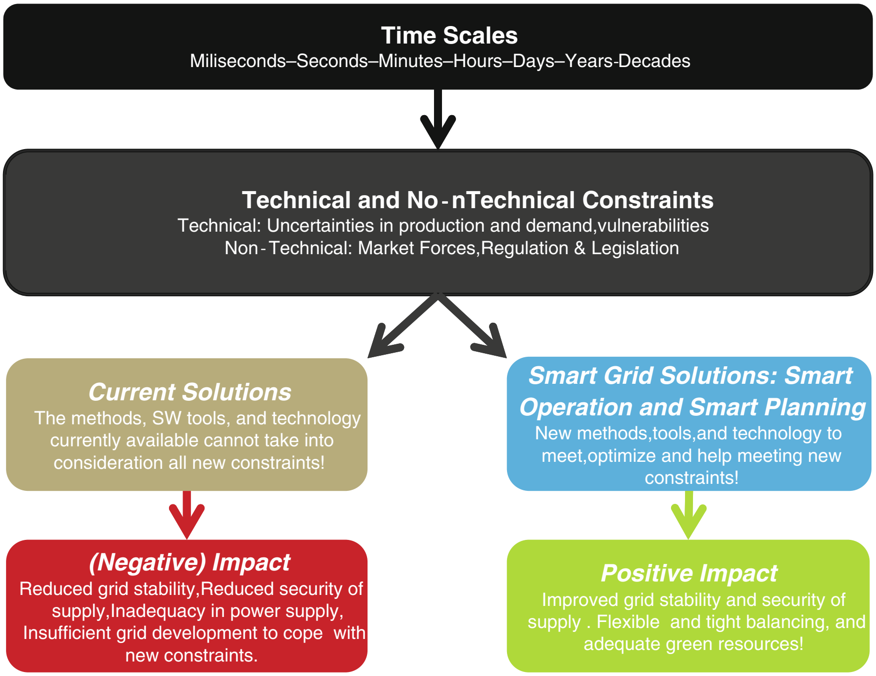

Fig. 3 Need for smart transmission grid solutions: from real-time operations to planning

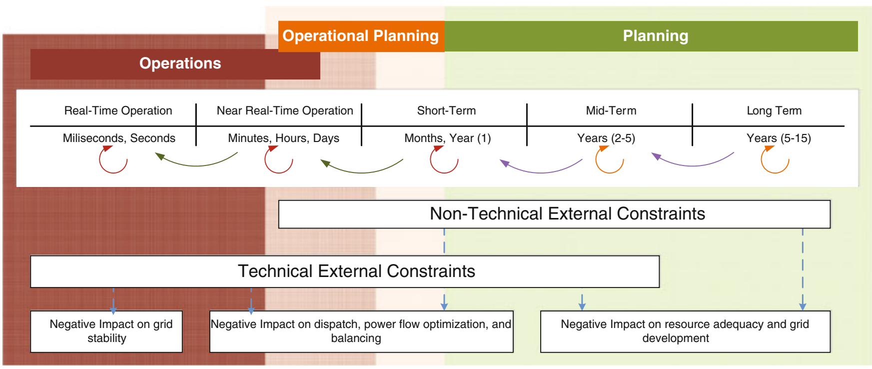

Fig. 4 Technical and non-technical constraints impacts on power system operation and planning

"actions" that a TSO must be able to take; this actions in turn will need not only power transmission technologies, but also software environments allowing for the implementation of new methodologies providing a possible change in paradigm in the operation and planning of the grid.

The result of the adoption of these new solutions need to provide improve grid stability and security of supply, flexible and tight balancing, and adequate usage of

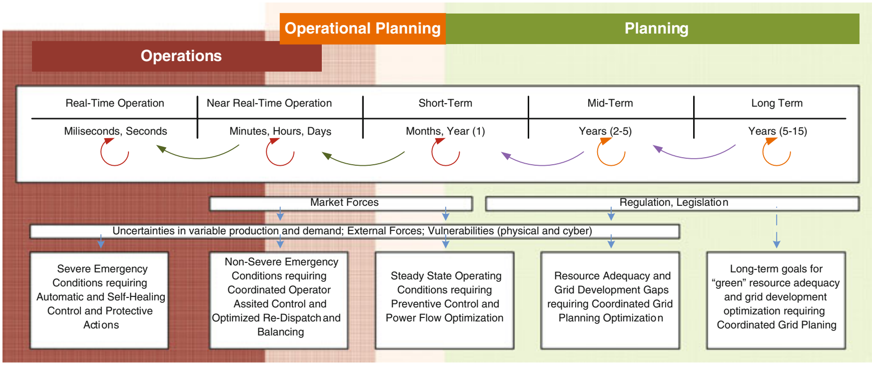

Fig. 5 Smart operation and smart planning solutions for transmission networks

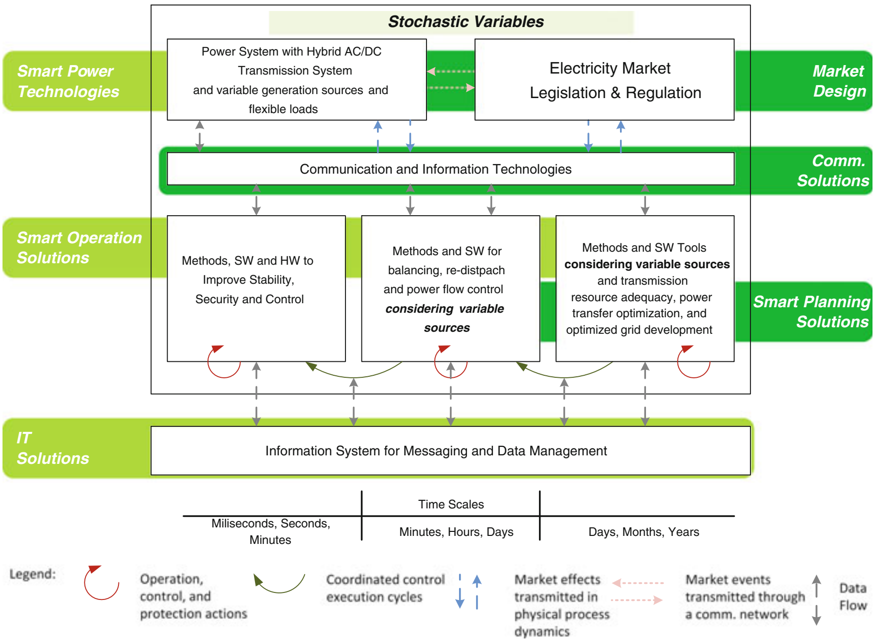

Fig. 6 Smart operation and smart planning research and implementation framework

energy sources. This will in turn facilitate the functioning of the integrated European electricity market and, furthermore, help in attaining the ambitious EU 20-20-20 goals.

A framework that allows the interaction of different solutions is conceptually illustrated in Fig. 6. One could envisage such framework as a massive distributed computer system, interacting between different software (SW) and hardware (HW) solutions which allow the implementation of technologies, methods, and tools that address particular technical and non-technical constraints at every timescale. Such software system is of course futuristic and perhaps not possible to achieve, but the architecture in Fig. 6 provides for a framework that helps identifying what is needed and how each of the solutions will interact to support different roles at the transmission system level. Hence, this framework can be used for identifying research areas that need to be addressed toward the development of STGs.

There are key benefits for a transmission system operator to be derived from adopting such a research framework, it will allow TSOs to identify and support work toward the integration of different grid technologies and users, e.g. renewable energy sources and new demand (electric vehicles). Smart operation and smart planning solutions will help in exploiting these technologies by the following:

- Achieving green goals by enabling the capability of the grid for renewable energy sources integration
- Ensure market competitiveness by making possible affordable electricity pricing with high-quality standards
- Increase grid stability while maintaining flexibility in system operation
- Guarantee security of supply under increase reliability compatible with societal needs

In the next sections, we review research challenges on some of the identified areas in Fig. 6, focusing primarily in the necessary technological building blocks and applications that can aid in improving grid stability, security, and control and that facilitate better resource adequacy while being compatible with regulatory constraints and organizational philosophies.

3 Smart Operation: Enhanced Monitoring and Control of Transmission Grids

Smart operation and smart planning solutions such as those envisioned in Fig. 6 to cope with the technical and non-technical constraints shown in Fig. 5 will require improved awareness of the current system state, and the possibility to act using that additional information. One of the cornerstones of that heightened ability lies in the exploitation of synchronized phasor measurement technology and a supporting IT and communications infrastructure. In this section, we highlight the state of the art, roadblocks, and potential showstoppers that smart operation will face and outline a direction for the development of methods and tools that can have actual applicability for enhancing grid stability, security, and control.

3.1 Synchronized Phasor Measurement Technologies as Building Blocks for Smart Operation Tools

3.1.1 State of the Art in Grid Monitoring and Control

The current approach for power system operations at the transmission level is to perform most of the monitoring and control actions within an energy management system (EMS), which makes use of a supervisory control and data acquisition (SCADA) system as illustrated in Fig. 7. The SCADA system supplies non-synchronous time-skewed measurements every few seconds to a state estimator (SE), which are obtained through round-robin polling. The SE uses these measurements along with the topology determined by a topology processor to provide an approximation of the "state" of the system in its current operation condition. Note that the "state" of the system consists of an estimate of the voltage magnitude and angle, transformer taps, and other quantities related to the SE model utilized. This estimated state is used for initializing several applications such as contingency analysis, optimal power flow, and other applications such as static security analysis, and for the initialization used in dynamic security assessment. Observe that due to the slow rate of acquisition of the SCADA system and the dependency of these operation tools on the starting point from the SE, applications are executed with a time lag as compared with the current operating condition of the power grid.

There are many solutions available and currently used by transmission system companies and system operators. Although these systems are mature and dependable, it has not been until recently that wide-area features have been added to these systems. Wide-area PMU-based features are not broadly adopted and have a reduced number of available phasor data applications, such as to support conventional state estimators as illustrated in Fig. 7. Observe that in this case, the PMU data are merely used to provide additional measurements into the state estimation process; however, the SE does not take the advantage of the time-synchronized measurements from the PMU and simply treats the data as an additional measurement source as done with conventional remote terminal unit (RTU) measurements.

In addition, the existing systems were not developed to withstand the strain of managing the data volumes from the streaming of synchronized phasor measurements in an efficient manner [45]. Despite these limitations, there are initiatives in North America which have created specialized systems exploiting phasor measurements with the aim of enabling new applications of PMU data and increasing the utilization of synchrophasors in operations [44]. New applications must take full advantage of not only the higher sampling rate from PMUs, but also from their time synchronization features and additional information provided by them. To take full advantage of PMU measurements, adequate software systems to support operation applications must be developed with a philosophy of modularity, scalability, connectivity, interoperability, and redundancy, for which current software systems to support PMU applications are not designed.

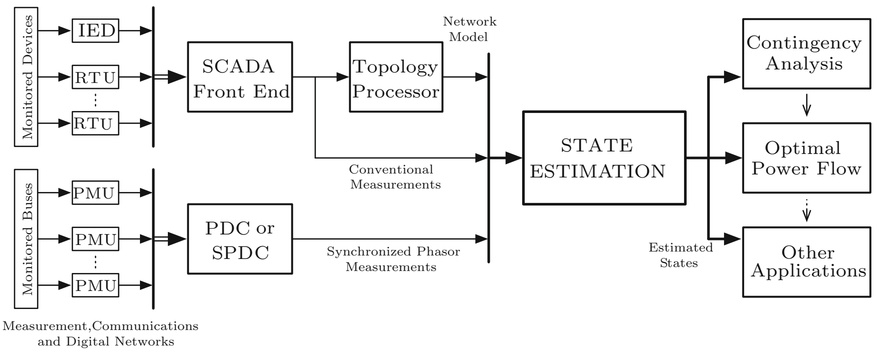

Fig. 7 A conventional SCADA/EMS system supporting operation tools

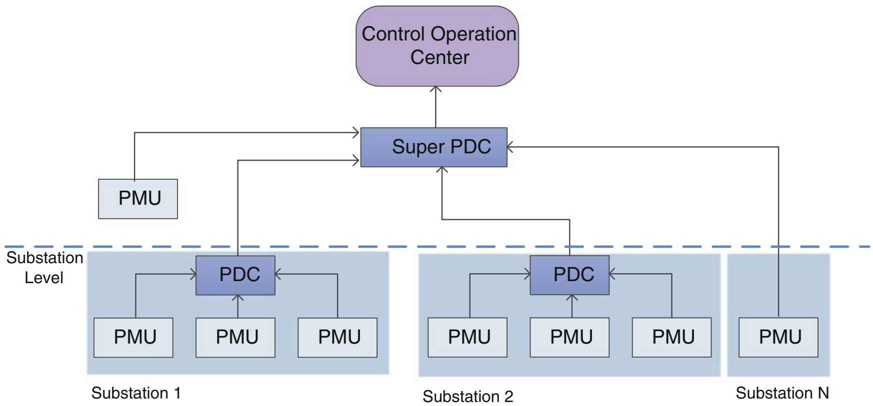

Fig. 8 A typical hierarchical WAMS layout

3.1.2 Synchronized Phasor Measurement Technology

The new enabling technologies of so-called wide-area monitoring systems are PMUs as the measurement device of choice, and their supporting infrastructure which is formed by communication networks and computer systems capable of handling PMU data and other information [usually called phasor data concentrators (PDCs)]. The set of PMUs and their enabling information and communication infrastructures is termed SMT [7].

Figure 8 shows a typical layout of the communication between PMUs and PDCs. The PMUs are the actual measurement units dispersed throughout the power grid, at substations, major interconnection points, and main generator sites. The PDCs then receive the signals from several PMUs and/or PDCs, aligning the measurements and output a stream having the aggregate of these measurements.

PDCs may also include historians archive data for detailed analysis and off-line applications. PMUs can also include other critical state such as breaker position (digital I/O, speed messages, etc.) to record alongside the phasor measurement into the historian or for real-time applications.

PMUs and PDCs can typically produce multiple streams, which among other things are used to feed redundant control centers over redundant communication infrastructure. These streams can also contain subset of available data, such that lower rate streams might be used for some applications while historians and dynamics analysis tools may receive the full rate.

PDCs are typically located in a substation or at a transmission operator center in order to aggregate the traffic from several PMUs within that substation or operation region. These PDCs can forward concentrated output streams of either all or selected measurements to an upper layer. This will continue in hierarchical fashion, and at the end of the aggregation tree sits a PDC often nick-named "SuperPDC" which essentially has all the streams of PMU data available for the operational center analysis.

The challenges faces by this hierarchical model have been realized and NASPINet offers an alternative model for data transfer [38]. The adoption of the NASPINet model in North America has not yet been fully realized, and it is not clear whether this model will be adopted elsewhere in the near future [4]. It is, however, known that each of the TSOs realizes their networking according to similar principles to those of NASPInet, with typically a redundant control operation center and network infrastructure.

With the rising number of synchrophasor installations around the world [46], a window of opportunity opens for stakeholders in the transmission system to exploit the time-stamped measurement data and higher resolution provided by PMUs. However, the number of applications available to transmission operators for exploiting these measurements seems to be insufficient to justify investments in SMT. New applications that support the smart operation of the power system would justify these investments and therefore need to be developed.

3.2 Technological Challenges

3.2.1 Need for Continued Standardization

The IEEE Power System Relaying Committee (PSRC) defined the standard for synchronized phasor measurements in substations in the IEEE Standard for Synchrophasors for Power Systems, i.e. IEEE STD C37.118-2005 [30]. This standard addresses the definition of a synchronized phasor, time synchronization, application of time tags, methods to verify measurement compliance with the standard, and message formats for communication with a phasor data concentrator.

A comprehensive set of tests and calibration methods were conducted on a number of PMUs to assess all aspects of their measurement performance before being deployed in transmission, such as those reported in Moraes et al. [37]. However, in 2009, the IEEE started a joint project with IEC to harmonize real-time communications in the IEEE STD C37.118-2005 with the IEC 61850 communication standard to introduce measurement accuracy under steady-state conditions as well as interference rejection.

As a result, the original IEEE STD C37.118-2005 has been improved and split into two standards, one for measurements (the C37.118.1-2011 [31]) and another one for communication (the C37.118.2-2011 [32]). On the other hand, for the operation of a Phasor Measurement Unit (PMU) to be qualified, the units' performance should comply with the accuracy requirement stated in the C37.118.1-2011. Hence, IEEE PSRC provides guidelines for synchronization, calibration, testing, and installation of PMU in the IEEE PC37.242-2012 [28]. This guide also covers the associated interface requirements for communications testing to connect PMUs to other devices including phasor data concentrator (PDC) as given in the C37.118.2-2011. In addition, the performance and functional requirements of typical PDCs or PDC systems such as synchrophasor data processing, real-time access, and historical data access must be verified to conform to the suggested guide named IEEE PC37.244 [29]. This guide also described PDCs test setups and some user applications.

Despite this recent large effort on standardization, most of the currently available PMUs are not meeting the complete specification of the current standard C37.118.1-2011. This is due to a lack of specific application requirements that have to be met by the instruments. Further, the recent standards on PDCs open now the door for a further discussion on how PDCs should provide standard output to support PMU applications so that they are independent from particular software systems and manufacturers. The standardization work is certainly progressing at a reasonable pace; however, attention must be paid into guaranteeing modularity and interoperability of different software systems that will be supported by PDCs for implementing advanced phasor applications.

3.2.2 Big Data Management

There are several reasons for the lack of SMT-based applications and their limited adoption. These reasons emerge from the two different development approaches currently used: application development using real PMU data and the simulation approach. From a researcher's stand point, obtaining real PMU data from transmission companies involves signing non-disclosure agreements which delays the start of research efforts, and more importantly, they may impose restrictions on the intellectual property of the derived works [41]. Foremost, when developing PMU-based applications, the PMU data itself are not sufficient: knowledge about the transmission system model parameters during the archived data time frame and other data (such as bus-bar level breaker status) are crucial for some applications [33] and may not be easy to obtain or interpret. Despite that the COMTRADE format has been selected for PMU data sharing in North America [1], due to regulations for postmortem forensic analysis [40], these data format may not be the most convenient for application development and straightforward data analysis.[1]

Many applications require large records of phasor measurements (from 1 day to even weeks of archived data [59], and this from multiple PMU). Data availability and correct sharing mechanisms are not only an issue for academic researchers, but may also become important for application developers looking to extract features of data from massive data sets [52]. The industrial development and adoption of these applications can be further delayed if adequate software systems to manage these data sets are not available.

3.2.3 ICT Aspects

Many academics have proposed applications of PMU data based solely on simulations using software commonly used in the power industry (which are mostly positive sequence-based (or phasor) simulations). While this approach is suited for some fundamental research, it might not be appropriate for actual implementation. This is because this approach does not take into account many of the challenges and characteristics of PMUs and the ICT systems. As a result, unreasonable assumptions of what the capabilities of these enabling technologies are made, often through an insufficient of the underlying technology limitations [58], although some of them have been acknowledged [35].

Current approaches for simulating the use of remote data for control purposes are considerably easier than the actual implementation, where appropriate data filtering, transmission to a PDC, processing, and transmission to the (remote) controller are needed. This requires several different stages where practical issues and possible delays occur. Without full consideration of these practical issues, it may not be advisable to install these applications at a control center without going through a thorough testing process. This highlights the need of both more realistic simulation approaches as those used by other communities [13, 42] and the possible uses of co-simulation of cyber-physical networks [50].

Beyond aspects of data transmission, time synchronization over wide geographical regions will continue to pose several challenges. An example of one of such practical issues is illustrated in Fig. 9, where the voltage phasor angle from PMUs installed at three different substations in the Mexican power system is shown. This figure shows the effect of GPS signal loss of in the THP-LBR and LBR-THP voltage angles. The trace of the LBR-GUAT angle shows no issues with the GPS signal. Such issues with PMU measurements, and other similar ones [58], need to be taken into account while researching new time and data transfer architectures that can be adequately employed by industry. This example illustrates

[1] Somehow, the power industry continues to overlook how other fields of research have dealt with massive amounts of data and have developed formats that allow to work and exchange numerical and graphical data efficiently [22].

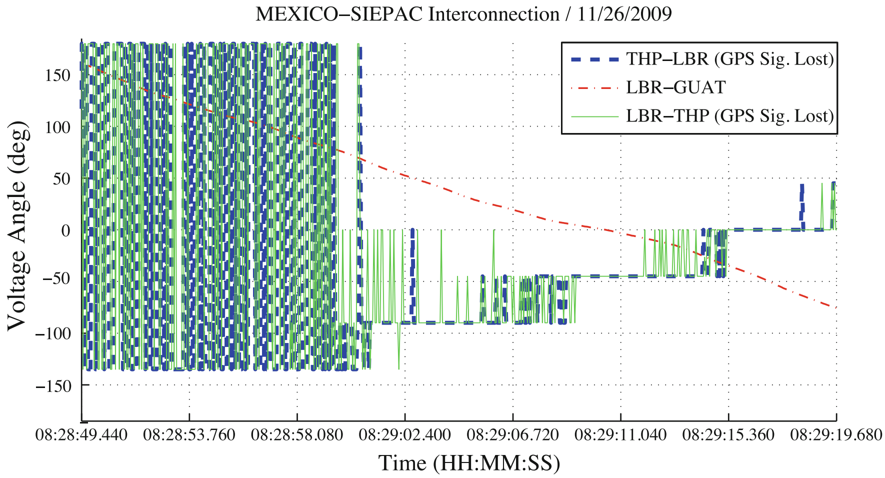

Fig. 9 Effect of GPS signal loss in PMU data

the need for GPS time-independent timing and data transfer, for which technologies developed in other fields such as digital television could be applied [25].

3.2.4 The Requirements Dilemma

With the considerations made above, we realize that there is a dilemma on determining the appropriate ICT design specifications for each particular "application." The dilemma arises because not all the future applications enabling these STGs according to these principles have been developed. In order to be developed correctly, they need "an" ICT infrastructure, which in turn needs application specifications for its design. A new approach for R&D is necessary to flexibly evaluate different ICT paradigms at the same time that the power system operation and control strategies are being developed. Two approaches might be suitable for tackling this dilemma: the proper use of holistic simulation environments [13, 42] and co-simulation [50], and the availability of experimental facilities for testing and validation [57].

3.3 Smart Operation: A Way Forward and Future Grid Monitoring and Control Solutions

3.3.1 Holistic Architectural Analysis

An STG is more than a grid that takes benefit of PMUs and requires ICT for this purpose. At a minimum, a STG should make use of these data in order to exploit all the available "observability" and "controllability" in a power system through closed-loop feedback control and to coordinate system control with protection. As such it can behave as a "self-healing" system, or at least utilizing the system more securely through increased awareness. To this extent, all measurement devices should be capable of producing synchronized and high-resolution time-stamped data that capture the dynamic behavior of the power system and can provide system observability. Controllability can be effectively provided by all those devices that can be in closed-loop control including conventional generation, flexible AC transmission systems (FACTS), high-voltage direct current (HVDC), and tap-changing and phase-shifting transformers.

To accomplish these ambitions, STGs should contain more than the high-resolution measurements provided by PMUs. In Fig. 10, a conceptual diagram of a "centralized model" for a STG is shown. In such STG, synchronized measurements are obtained at transmission substations through time-synchronized measurements not only from PMUs but also from other envisioned highly accurate measurement systems retrieving data from controllable devices and protective device "information sets" (i.e., all available information from within a protective relay). This plethora of data is sent through communication networks, received, and concentrated at a decision and control support system that determines appropriate preventive, corrective, and protective measures. This support system is the cornerstone for enabling STGs using synchrophasor data, and it is here where the newly developed analysis techniques will produce "smarter" decisions allowing the power system to operate more securely, efficiently, and reliably. The decisions determined by this support system will then support operators at control centers to take "smarter operator control actions" or even device "smart-automatic control/protective actions." These actions are translated into feedback signals that are sent through communication networks to exploit the controllability and protection resources of the power system.

Note that although the diagram shown in Fig. 10 is a centralized model, there can be other more decentralized models for STGs. A "decentralized model" of a STG would divide the system into "focal area" systems with different operational functions (some of them might not include a focal area control center for example, implying that only other functions are taken there and thus a lower amount of data with perhaps lower quality of service (QoS) is needed) and a "wide-area" system. The data delivery is done through a publisher–subscriber model, such as Grid-Stat [21], instead of a traditional star communication with round-robin polling model used in traditional EMS/SCADA systems, whose limitations have been acknowledged in Bose [5]. Feasible approaches considered in Bose [2], Gjermundrod et al. [5], and Bakken et al. [21] have great potential and should be further investigated.

However, as mentioned before, the whole architecture of the system faces a dilemma as it will be determined by the requirements from different applications using PMU data, which in turn need the ICT infrastructure to be developed—in other words, how and for what purpose the measurement and other data be used will determine the most cost efficient system architecture. Yet, "an" architecture is needed to obtain data to develop the applications. To find the appropriate

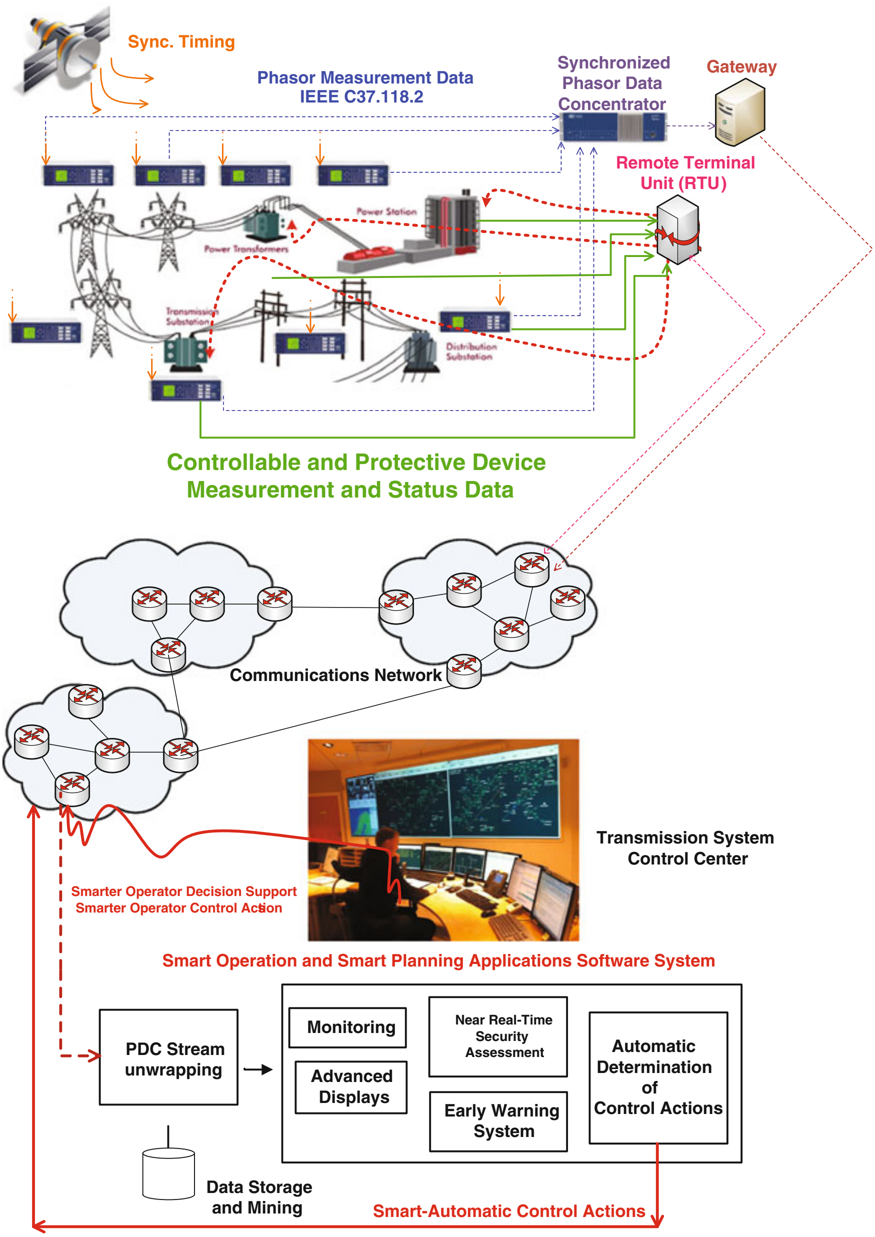

Fig. 10 A centralized model of a smart transmission grid

architecture that fits the needs of future power systems, appropriate experimental platforms for research are needed [54, 57], as well as the use of holistic simulation environments [13, 42] and co-simulation [50].

3.3.2 GPS-Independent Time and Data Transfer

Phasor measurements create real-time traffic, and this traffic needs to be transported over some network infrastructure. The real-time traffic has some timing issues of its own, and this suggests that low loss may be good.

Packet network analysis shows a variety of issues, in which real-time properties such as loss and delay becomes affected by interaction between other traffics. It is also shown that these behaviors have a high degree of unpredictability in them. The microscopic details of protocol interactions are many, but under the assumption that information gets transferred (or can be interpolated), the remaining macroscopic effect for the system is the average delay. The interaction between many other traffic streams can cause this average (over the control-loop bandwidth/time constant) to change over time.

Means to reduce jitter and to reduce loss will increase delay and still do not provide predictable results.

Delay and delay stability are major issues in ensuring control-loop stability and meaningful reaction time to achieve the control goal. Power grid controls, such as damping controls (e.g., PSS and POD), could potentially be tuned to compensate for delay, but large variations of delay over time would require self-tuning, which would add to the system complexity. An alternative approach is to reduce the control-loop bandwidth, which makes it too slow to react to actual problems in the power grid.

The involved signals have real-time properties; this means that low delay and low jitter are required. Loss and high jitter will require additional delays to the signals, and this is clearly not a good property for the overall system behavior.

In order to meet the requirements, an alternative network solution is proposed, where technology developed for the real-time networks of radio and TV broadcast networks can be utilized. Such network has similar requirements on low latency to handle long-distance live broadcast (interviews, sport events, etc.). The network solution offers stable latency requirements to handle the low jitter tolerance of broadcasting and production equipment. It has the low loss requirement typical of live transmission, as there is no time to do re-transmit of information.

There are similarities between the power grid needs and the properties provided by such communication network solutions [14, 25]. Among the similarities lies a high QoS need for the real-time streams, bounds on propagation delay, low jitter, low loss, and high reliability. It distinguishes itself by providing significantly higher real-time properties compared to typical IP SLAs and even MEF 2.0 requirements.

Another aspect is the need for precision timing, which may be available in the communication network solution [25, 39]. The detailed requirement varies from network to network, but lies in general in the region of ± 1–4 μs from the reference time, over a 10-hop network. Comparing this to the PMU need of ± 26 μs [32], we see that this solution can support the PMU needs.

A detailed analysis and other communication network challenges for synchrophasor-based wide-area applications are presented in [9].

3.3.3 Software Development for Real-Time PMU Applications

Today, researchers need to devote large efforts developing mechanisms that allow them to use PMU measurements, e.g. PMU data extraction for off-line applications and real-time data mediation for online applications. These tasks are especially difficult in the case where PMU equipment and PDCs are provided by different vendors.

Figure 11a shows the main difficulties in today's monolithic vendor-specific PMU application software development environments. As it can be observed, once the infrastructure is put in place with PMUs installed and networked through a communication network, all real-time data arrives to a PDC. At this stage, all of the data are locked into a vendor-specific software system which may or may not provide its users with the necessary tools to implement applications. If these tools are available, they are heavily reliant on the software libraries provided by the vendor and offer limited integration options. On the other hand, historical data that can be used for off-line analysis and applications (e.g., data mining) are also locked into a proprietary time series database system specific to the software system. As a result, the user has few possibilities in implementing new applications without relying on the software system provider. This limits the possibilities of exploration and interfacing with external tools and software systems. Hence, it is realized that once the data arrive at the PDC, and concentration and alignment functions have been carried out, the PDC could be interfaced with standard protocols to a flexible development environment.

In order to develop applications for monitoring and control based on synchrophasor measurements, it is important to have real-time access to the individual quantities (phasor/analog/digital) of each PMU, which are wrapped inside the real-time PDC stream. The IEEE C37.118.2 standard has provided the specification for the creation of "concentrated output streams" from a PDC, with PMU data coming out aligned and concentrated into a single stream routed to another larger PDC (i.e., the SuperPDC). Although this facility was meant to be able to concentrate and align the PMU data from different PDCs, it offers the possibility to decouple the development of applications from the PDC.

The use of concentrated output streams provides a mechanism for standardized real-time data sharing that can be used to interface with alternative software systems from that of the PDC provider. Thus, instead of building monolithic software architectures and systems, it possible to develop a modular approach to software development by exploiting synchrophasor standards for real-time data communication. As such, applications can be deployed in different clients and

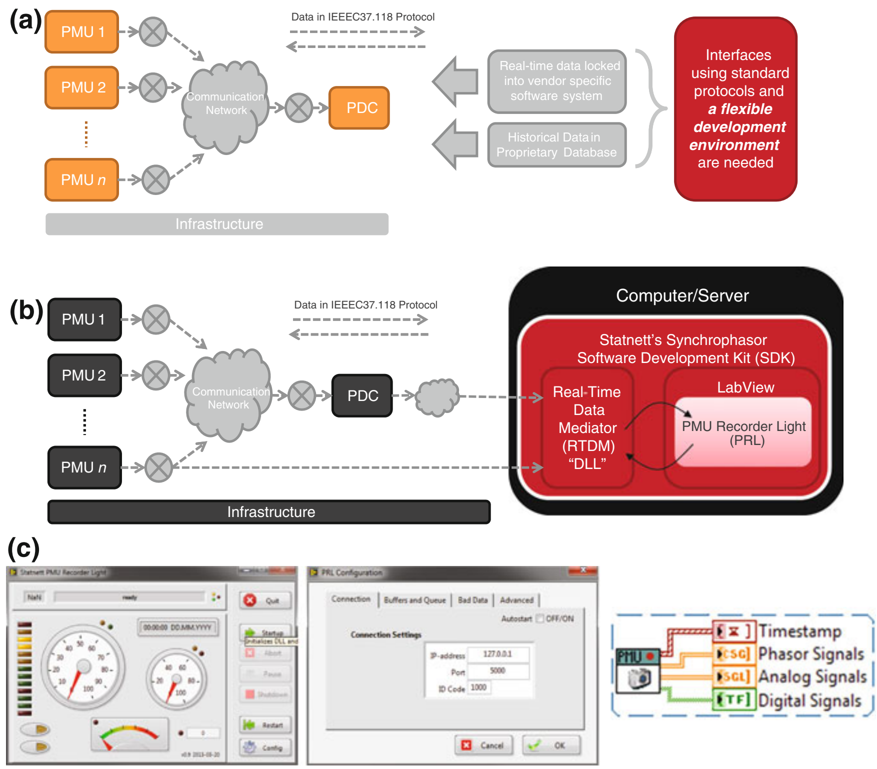

Fig. 11 Statnett's synchrophasor software development kit (*SDK*) for modular, real-time, PMU application development. **a** Limitations in monolithic software environments for developing PMU applications. **b** Statnett's synchrophasor SDK for modular PMU application development. **c** Statnett's SDK PRL configuration and user interface

meeting different application requirements. This is not yet possible with today's software solutions available in the market.

To exploit this possibility, a software development toolkit was developed by Statnett SF (the Norwegian Transmission System Operator) [56].

The main components of the SDK along with the possible interfaces to multiple PDCs or PMUs are illustrated in Fig. 11b. The aim of the SDK facilitates research, fast prototyping, and testing of real-time synchrophasor applications. The SDK enables the usage of high-level programming languages such as LabVIEW, regardless of the equipment used and its manufacturer, thus providing platform independence for research and development. This property enables users to be more focused on developing synchrophasor applications and not on platform-specific implementation issues. The SDK is capable of connecting to an arbitrary number of PMUs or PDCs compliant with the IEEE C37.118.2-2011 protocol.

The SDK provides a real-time data mediator that reads and stores real-time data in a configurable buffer (RTDM in Fig. 11b). The RTDM is built on a client server architecture allowing the connection of multiple clients providing data in the IEEE C37.118.2-2011 protocol, and enabling the access of these data by methods. The RTDM is compatible with several operating systems, and in the Microsoft Windows operating system, the RTDM is compiled in a dynamic link library which is accessed by a client. Further details on the RTDM will be available in a future publication.

The clients can access the data and other information from the PDC using a library of methods. Currently, as shown in Fig. 11b, the content of the buffer is accessible in the LabVIEW environment through different functions in a library named PMU Recorder Light (PRL), which provides a standard LabVIEW function control (VI). These libraries are illustrated in Fig. 11c, showing the GUI for data access, the configuration for connection to output streams, and one of the LabVIEW blocks providing access to real-time data. The LabVIEW platform is selected because it provides easy integration with different hardware equipment as well as intuitive graphical programming language (G language) which supports integration with MATLAB, C++, and other programming languages.

The PRL has two major components:

- Data collector: This component reads the data from the PDC/PMU and stores them in configurable buffers.
- Data extractor: This is a collection of functions (VIs) that allows the user to access the buffers and queues in the PRL. It reads the data from the buffers and provides the user with control over the data streams in a form suitable for further processing (i.e., as a signal data type in LabVIEW).

Such modular approach for accessing real-time streams provides large advantages for prototyping PMU applications and application deployment possibilities. We illustrate this for the case of real-time display of PMU data, other real-time applications developed can be found in Vanfretti et al. [57]. With current monolithic approaches, the display of PMU data is confined to the control center and tied to the PDC system receiving the data. In contrast, the SDK offers multiple deployment possibilities. Figure 12 presents two of them: integrated computer/server environments in Fig. 12a which can be deployed in multiple computers, and the deployment of PMU applications in mobile devices. In the first case, the SDK along with a custom application for visualization is deployed in a single or multiple computers/servers, allowing multiple users to visualize the data.

In the second case, the SDK is deployed together with a custom application offering a publishing mechanism to feed the visualization application in a mobile device. Figure 13 shows the applications running on Apple's iPhone smartphone and the iPad tablet.

Smart Operation Tools: Monitoring and Control Applications

Statnett's Synchrophasor SDK illustrates how the development of measurement-based real-time PMU applications can be deployed in different environments. This

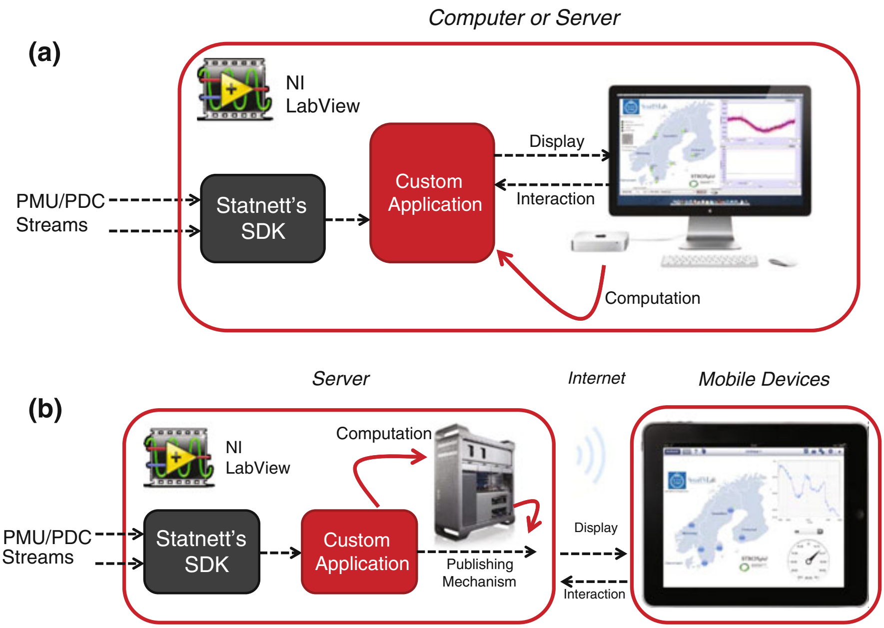

Fig. 12 Deployment of Statnett's SDK in different computer system architectures for powering PMU applications. **a** Development of Statnett's SDK in integrated computer/server environments. **b** Development of Statnett's SDK powering mobile applications

Fig. 13 iPhone and iPad PMU data visualization Apps powered by Statnett's SDK PRL interface

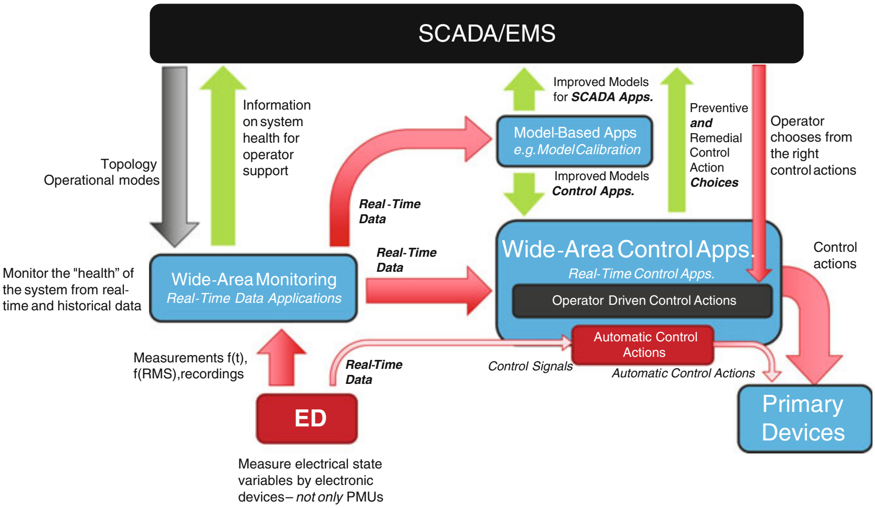

Fig. 14 Holistic system architecture for smart operation applications

flexibility would allow to achieve smart operation applications software systems as envisioned in Fig. 10. This system should be able to holistically exploit both measurement-based as well as model-based applications as illustrated in Fig. 14.

Such architecture should take advantage of tools such as Statnett's SDK for deploying real-time data applications for measurement-based monitoring and stability assessment, near real-time, and real-time control actions through operator-driven control and automatic control loops. Although there are no flexible solutions to integrate model-based applications, the architecture should support model-based stability assessment tools and allow for the interaction between measurement-based and model-based tools. One example is the provision of a model calibration application that uses real-time measurements to calibrate the dynamic power system model which is used in both stability calculations derived from models as well as in real-time control applications.

The emergence of smart operation applications will depend on a software architecture that provides these features and allows for a flexible deployment of the different components needed in disparate software and hardware architectures. To achieve this, such architecture should be modular, extensible and be able to re-use components in different targets for deployment. Statnett's SDK is a step forward in this direction; however, much work is needed to transition from today's monolithic and vendor-specific software systems, to a modular and flexible software system to support power system smart operation.

4 Operational Planning of the Smart Transmission Grid

4.1 Organization of the Energy Supply Chain in Europe

In earlier days, before the mid-1990s, the operation of the electric power system in Europe was rather straightforward, with vertically integrated companies that owned and controlled the entire value chain. As a result, the entire decision-taking process was largely done within in a single company and this for the different time frames. At that time, the security of the energy supply at an acceptable cost was the main objective.

Through the process of liberalization, the European energy system became regulated and unbundled, with separated generation, transmission, distribution, and retail. A regulator sets the rules of the grid operation. In view of the smart grid, the regulator plays a vital player as he forms the main influence on grid rules and tariffs and has a strong voice in the investment process. In a sense, the regulator even defines the different players. Within a smart grid, all stakeholders are able to optimally perform their tasks, taking into account the limitations associated with stakeholder interaction. Interaction between stakeholders happens between similar stakeholders (e.g., between TSOs in different countries) or between different ones such as generators and the TSO. The required interactions (and communication) has significantly increased, for instance related to the use of ancillary services.

When looking at the interconnected European power system and its stakeholders, a complex patchwork of different entities with different tasks, objectives, and non-overlapping geographical areas can be seen. The non-harmonized regulatory framework adds to the complexity and is a serious constraint to the development of a true smart grid at an international level. Ongoing efforts of the EU (through the Third Energy Package [15]) are a first step toward a more harmonized energy policy. The Third Energy Package caused the creation of ENTSO-E, the association of transmission system operators in Europe, and ACER, the agency for the cooperation of energy regulators. The actions of these organizations aim to manage the international interactions between guidelines and to harmonize the framework throughout the European power system. When considering this international power system as the setting for the STG, it is essential to recognize the importance of the complex interaction between the different regulatory frameworks and the roles of the stakeholders.

4.2 System Working up to Its Limits

In the pre-liberalization era, the generators and grid were part of the same company that owned, maintained, and operated the grid. The grid owner had the means to make the necessary investment decisions based on a coordinated planning (generation investments coordinated with necessary grid reinforcements).

These generation investments were mostly large, traditional generating units following the principle of economy of scale. If possible, the generation was planned located close to the load centers.

The system operator could control all aspects of the power system: generation for unit re-dispatch and managing the grid and its elements (line opening, capacitor switching, etc.) to control the system flows and avoid line overloads.

After being unbundled, the TSO still makes the investment decisions and manages the power system. However, he experiences several limitations in this respect. Generation investments are no longer coordinated with grid expansion, or rather, they are performed by independent organizations. The result is the shift of generators closer to the source of energy, e.g. the harbor as a location for coal-fired power plants.

The newly installed generation capacity is often also of a different type than it was before. Generation units from variable power energy sources are more commonplace due to the strive for more renewable energy generation and the emergence of other small-scale generation such as CHP (combined heat and power). These devices are not only not predictable to a large extent, but also uncontrollable by the operator. A more unpredictable power injection pattern will cause a higher uncertainty of the energy flows in the system. The increased market working has also led to a higher volatility of the energy flows. At the same time, there has been a lack of investments in the transmission system. The effects are seen most prominently when looking at the interconnections between zones. Additionally, the permitting process for generation is often considerably shorter than that of transmission, mainly due to projects that are postponed due to opposition from public, ecologists, etc.

The variable power injections in the system cause fluctuating flows on the AC grid. The system operator can still control the grid to manage these flows, but redispatching generation has more difficult and costly. As a result of the increase in variable energy flows, the limited grid investments, and the reduced control options for the system operator, the grid is being operated at a higher uncertainty [43]. This means that it in some cases is operated closer to its limits, with potentially serious consequences for grid security, while on other cases the system might not have been used up to its potential, with a negative influence on the social welfare. In order to manage the system under these circumstances, three main innovations are needed. The grid operations need to become more flexible, increased coordination is required, specifically between different zones, and the manner in which the security is dealt with needs to be redefined.

4.3 Flexible use of the Power System

Simply put, the transmission of electrical power encompasses two fundamental aspects: on the one hand, the balance between generation and load needs to be maintained, while on the other hand, the system has to remain within the security limits. For both aspects, the requirements with respect to flexibility have significantly increased due to higher uncertainties and fewer control means [60].

4.3.1 Flexibility of Generation and Load

Maintaining the balance between generation and load is one of the classical problems within electrical power engineering, specifically because storage of bulk quantities of electrical energy in a cost-effective manner is difficult. However, a number of aspects have changed in the modern power system, both on the generation and the load side.

First of all, a larger proportion of energy is delivered by sources with a fluctuating output. Furthermore, these fluctuations occur at a higher frequency than those originating from classical generators resulting in faster control requirements and extensive balancing services. A second effect is that a significant part of the generation is either not flexible (e.g., most nuclear power plants) or not centrally controllable (most renewable energy generation). As a result, little the remaining "flexible" generation is responsible to take care of all the fluctuations, which can have an influence on the economics of those generators. In some cases, the non-flexible generation might even surpass the load, e.g. at moments of low load and high-renewable infeed. At such moments, there is no or insufficient downward regulating capacity [12]. A third change is the increased use of power electronic converters as an interface between the generation and the grid. These converters normally decouple the generation, and with that also the inertia, from the grid. As a result, the system inertia decreases which causes an inherently different dynamic behavior of the grid and higher-frequency deviations in case of a disturbance.

Also the load perspective has changed considerably. On the one hand, there is renewed attention for demand response or demand-side management. The potential of aggregating smaller loads on the distribution side and to use them to manage the frequency is expected to bring a considerable contribution to the balancing needs. Similar as for the generation, also loads are increasingly connected to the mains supply using power electronic converters. The effect of reduced load inertia is however smaller than that of the generation. Also the ongoing developments of storage devices make that electrical energy storage can become a more prominent option, next to the already existing pumped storage facilities. Whether storage will be used in a distributed manner or centralized, and whether the main application will lie in short-term or longer-term balancing is yet to be seen. In any case, storage can offer services within the larger system, but it is not a separate service in itself.

The main hurdles for the development lie in the correct integration of the different levels of flexibility among stakeholders, and this in the different operational time frames. This includes the integration of such services into the market and providing all stakeholders the right (price based) incentives. Without these incentives, the necessary investments will not happen. Another field of research is making use of the control capability of power electronic converters to provide ancillary services such as inertia to the energy system. Traditional power engineering approaches to dealing with load and generation might change dramatically where one see the change from the original generation which follows load, toward load flattening and eventually the combination of generation, load, and storage following the profile of renewable generation that operates at a very low marginal cost.

4.3.2 Extended Grid Use through the Dynamic Use of Existing Assets

Grid operators in the pre-liberalized energy system had quasi-full control of the system, including generation redispatch (which came at a cost which was socialized among users). This is no longer the case in the unbundled system. As a response to the lack of control means available to the system operator and to increase transmission capacity, new ways of providing flexible grid operations are sought for. In this subsection, the approach to manage the flexibility of the grid during operational planning is performed in the NetFlex demo, part of the EU FP7 project Twenties.[2]

A first option is the installation of power flow controlling devices (PFCs) to manage the power flowing through the grid in a more dynamic manner. These devices can be used to redistribute the flows from the heavily loaded lines to the less congested lines. The PFC can be used to free capacity on the market (D-2) and plan the system in such a manner that it can be operated securely (D-1) and be used as a means to solve problems intraday (either as preventive or corrective action). Results from the NetFlex demo have shown that the use of PFCs effectively reduces the flow on transmission lines with an insufficient margin and therefore reduce the need for redispatch [24]. It was also shown that through adequate scheduling (D-1) additional margin could be created to manage also uncertain generation patterns. It was also shown that the system itself was capable of "absorbing" significantly more wind energy without hitting the security constraints. Figure 15 shows the system capabilities in the month of January 2013 with uncoordinated operation (purple) and coordination of PSTs in the CWE region against the expected (P50) and high wind (P90), sorted from highest to lowest infeed [23, 24].

A second option is to make better use of existing infrastructure. One example of such techniques is the use of dynamic line rating (DLR). This technology takes into account the actual limit of transmission lines, which is strongly dependent on wind speeds, rather than the conservative seasonal limits. Also within the NetFlex Demo of the Twenties project, it was found that the actual rating of the transmission line is 95–99 % of the time, the gain in capacity beyond the seasonal rating is higher than 10 % and in 90–95 % of the time, the gain is higher than 20 %. It was found that using adequate forecasting tools, the predictions of the line capacity can be used to include them in operational planning. On a two-day and

[2] Twenties project: http://www.twenties-project.eu.

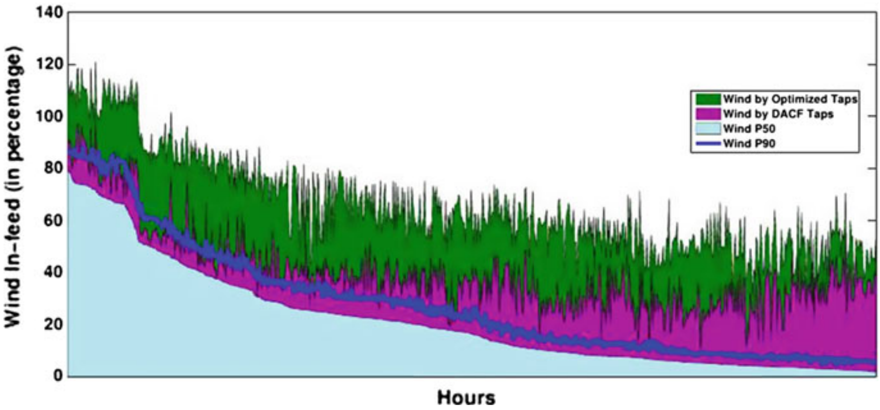

Fig. 15 Increase in system capabilities through the use of power flow controlling devices in the month of January 2013 for the CWE region [24]

day-ahead basis, the gain in capacity over the seasonal rating is higher than 5 % and in over 50 % of the time, the gain is higher than 10 %.

Both the use of PFC and DLR allow the operator to make a better use of the system by working closer to the system thermal limits. However, the remaining security margin becomes lower. Furthermore, by pushing the system to work closer to its limits, other security boundaries might be hit. As such, it is important to improve the monitoring of the system dynamic behavior. Within the Twenties project, a damping prediction monitor was developed, monitoring whether the dynamic limits were not reached while the thermal limits of the system were pushed.

4.4 Coordination in the Power System

As the operation of the power system has become more inter-zonal, with higher and more variable power flows through the system, more coordination is needed. In particular, because zones that are not directly taking part in energy transactions, are also affected by decisions made outside their zone. Currently, TSOs in Europe do coordinate the operation of the power system. There is an exchange in system data and operational information:

- Grid status (important scheduled outages)
- Day-ahead congestion forecasts are made
- Expected available transmission capacities are calculated
- Emergencies with possible effects beyond the local zone are communicated

However, the exchange happens on a very basic level. First of all, not all grid information is exchanged. One uses a “need to know” principle. An example is the load/generation data for the day-ahead congestion forecasts which are not shared independently, but rather as an aggregated quantity. Also information on the exact settings and status of devices (such as protection devices) is not always clearly communicated. One of the hurdles of this system is the exchange of data. Steady-state data are exchanged, but in a format which is generally not the one used for the internal studies where different tools are used, possibly in-house developed, with specific features.

Dynamic grid data are only rarely exchanged, and for this the data format is even more problematic as the different dynamic models used might differ significantly. Currently, no common data format exists, although that there are efforts in developing such a standard model (see CIM [34] and ODM [44]). However, significant improvements are needed in order to make them practical to use when many custom models are needed.

Not only the data sets that are used are different, also the tools and methodologies that are used differ among system operators. A good example is the $N - 1$ rule, which is one of the fundamental security rules in the power system and well known to power system engineers. However, when going in detail, it is clear that both the interpretations of "N" and "-1" differ between organizations. Even within one TSO, the concept of $N - 1$ usually differs between the grid planning and the grid operation department.

Nevertheless, this system of "need to know" communication works reasonably well, with only a limited amount of grave events occurring due to mis-operation (e.g., Italy blackout, August 2003; Germany-UCTE incident, November 2006). Yet, potential problems remain the following:

- Unidentified loop flows occur
- The uncertainty in the system remains high
- The "limited amount" of grave events mentioned before could have been avoided
- Problems might be solvable on a local level at a high cost, but could have been solved at low expenses elsewhere
- There is no system-wide perspective

The existing coordination in the transmission system is currently sufficient to keep the lights on, but more is needed in order to make optimal use of the available resources. The current framework does not allow an integrated operation of the power system. Considering advanced operating principles without taking the current background of cooperation into account will lead to unrealistic results.

4.4.1 Example: Coordination of PFC

A significant number of PFCs such as phase-shifting transformers (PST) or HVDC lines are installed between different zones. Although PFC exhibits a strong influence on the flows through neighboring systems, these PFCs are not operated in a coordinated way. As such, negative interactions between PFCs, both during steady-state operation and through dynamic interactions may occur. This problem is especially important when the controllable devices are operated by different system operators. Therefore, it is of substantial importance to deal with this issue when designing the controllers and during power system operation [53, 55].

Most PFCs are currently operated toward a certain objective which suits a single party. Coordination regarding PFC control is often limited to predefined rules and requires slow (often via telephone) interactions between the different participants. Coordination is limited for more than technical reasons: as the PFC is approved, installed, and paid by a local entity, this entity will use that asset to its optimum, without considering the "bigger picture." Using the devices to actively create capacity which can be used in the market environment is not possible in the regulatory framework. However, on the long run, it seems to be inevitable that controlling flows in the system will be come an ancillary service, which comes at a cost.

While there is significant potential in coordination of power flow coordinating devices, this potential is largely untapped at this moment. However, it is important to recognize the limitations in the system rather than searching for novel controller techniques that find no practical implementation.

4.5 Secure Operation of the Pan-European Power System

4.5.1 A New Reliability Concept is Needed

Modern society is critically dependent on a reliable electricity supply to cover basic needs such as food and water supply, residential heating, and ICT services. In the near future, electric mobility, distributed generation, distributed electricity storage, and other new uses will increase this dependency. Failing to provide a reliable electricity supply has far-reaching consequences for people, society, and the economy.

A power system's vulnerability is composed of its susceptibility and coping capacity [11, 20, 27]. A power system is susceptible to a threat if the realized threat leads to an unwanted event in the power system. The coping capacity describes the ability of the operator and the power system itself to cope with an unwanted event, limit negative effects, and restore the power system's function to a normal state. Thus, a power system is vulnerable if:

- at its intended function, it is susceptible to fail or operate with a significant loss of capacity,
- the power system is unable to cope with unwanted events and unable to quickly recover to normal function and full capacity.

The reliability of a power system is a combination of its vulnerability to external threats that can lead to failure modes and the implied consequences of such failure modes for the end-users (generators, consumers, and various facilitators, such as traders and suppliers). As such, reliability management is composed of two main subtasks: (1) reliability assessment and (2) reliability control. The overall objective is to ensure an adequate level of reliability while minimizing capital and operating expenditures. In reality, the reliability management is broken down into three main time domains in which the reliability management is performed, namely system development, asset management, and system operation, corresponding, respectively, to decision-making horizons of long term (years to decades), mid term (weeks to months/a few years), and short term (minutes to days). The $N - 1$ criterion was designed to set the reliability management target within the different activities and within the different control zones of interconnected power systems at transmission level. This criterion prescribes that the system should be able to withstand at all times the loss of any one of its main elements (lines, transformers, generators, etc.) without significant degradation of service quality. The two main intrinsic limitations of the $N - 1$ criterion are as follows:

- Strictly applied, it is an approach which does not take the cost of outages into account. This results in overinvestments in some instances and underinvestments in others, and hence a non-optimal social welfare.
- The $N - 1$ criterion is a "binary" criterion. The system is secure, or it is not.

With the rising uncertainty in electric power systems due to the introduction of renewables and the reduced observability and controllability which are a direct consequence of the liberalization of the energy market, this causes the $N - 1$ criterion to be increasingly difficult to use. The system needs to be overdesigned or underused to unacceptable levels, while the methodology does not allow to take adequate measures into account which rely on intelligent operation of the system using operator intervention or system flexibility. This also influences social welfare in a negative manner. These limitations are well known since the inception of the $N - 1$ criterion. Thus, for several decades, researchers and engineers have investigated alternative formulations to measure and enhance power system reliability. These are most notably probabilistic approaches which explicitly take into account both the probabilities of the external threats and the actual socioeconomic impact of service interruptions, to more systematically balance between the different decisions to be taken from the long term to the short term. Nevertheless, the $N - 1$ criterion is still massively used today, and this because the method was easy to understand, transparent, straightforward to implement while the new proposed methods are computational heavy, the electric power system was initially overdesigned, different implementations of the $N - 1$ criterion were used in practice, and most importantly, the method resulted in an acceptable level of reliability for the power system. This situation, however, is rapidly changing: The operating environment of the electric power system is gradually becoming less predictable. The low social acceptance of overhead power lines leads to system operation closer to its limits and to using more complex and, sometimes, more expensive solutions (e.g., underground cables, HVDC links, new conductors, FACTS). Technology has progressed very significantly, offering new opportunities to evaluate and control electric power system reliability. At the same time, the liberalization of the energy market and the consequent unbundling of the energy system have resulted in a multi-stakeholder business, where delivering the energy with the right quality and at the correct cost is increasingly important. System operators regularly need to take decisions which influence multiple facets of the energy supply at the same time. For instance, freeing more capacity to the market might have a negative effect on the system reliability: which level of transmission capacity is appropriate, and this two days ahead, day ahead or intraday? Investing in a new transmission line can be done using HVDC, AC cable, or AC overhead line. Each of them has different failure rates, repair times, electrical characteristics and consequently influences the system behavior in a different manner. Decisions taken in one decision time frame (long term, mid term, or short term) will influence those in the others: investments versus maintenance and making transmission capacity available to the market day ahead versus redispatch in real time if needed. It is not clear how to compare these different reliability related decisions: what is the correct metric and how to evaluate it.

Such a new reliability criterion will require a system infrastructure that transcends the current one, with higher information requirements, not only technical data such as generation and load data or component failure data, but also weather forecast data and societal data. Furthermore, the new methodologies will also require tools which up to now are not available to the community.

4.5.2 Power System Calculation Tools and Methodologies for the Pan-European Power System

The European power system is the largest system engineered by men. At this moment, no adequate tools exist to adequately model and compute the entire system in a detailed and time-efficient manner, or that make fully use of the available new technologies to make full use of them. New tools must be developed to enable the system operators to model and correctly control the pan-European network in the different time frames: from the millisecond range up to the operational planning range (days).

5 Conclusion

The challenges faced by the electric power industry are overwhelming, and it is clear from the discussions in this paper that a "reality check" on current research practices is necessary; particularly if future power systems are going to hinge on the design of technologies and procedures emerging from the smart grid "hype." To this extent, if smart grids at the transmission level are to become a reality, there needs to be an alignment in the current research practices. This alignment should consider the climacteric boundary interactions between policies, the regulatory background, technology maturity and, socially responsible and farsighted investment. Although we have not covered all possible aspects, we have highlighted the key challenges and potential pitfalls in the field of STGs research.

The different time frames in which the transmission system is managed are pivotal in the appreciation of smart grids. “Smarter” grids require adjustments in the operations and the operational planning phase. At the operational side, an increased use of advanced metering infrastructure, for instance from PMU, expected to bring considerable advantages to the power system. Nevertheless, challenges such as standardization, big data management, and ICT requirements remain. If these challenges can be met, the measurement data can be applied to improve system operations, for instance through the provision of improved control and protection functions. The use of new ICT technologies and especially the possibility of visualization allow the operators to become better aware of the system state take the appropriate actions.

From the operational planning perspective, system operators are setting the first steps toward a more dynamic grid operation, but additional research is needed. More specifically on the actual use of flexibility in the power system, including the stakeholder interactions and the coordination at the international level. However, the main challenge may lie in development of new reliability concepts which can be implemented in realistic power systems and that provide a maximum social welfare to the users, and for which adequate tools are still under development.

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